IN THE UNITED STATES DISTRICT COURT FOR THE DISTRICT OF UTAH

CENTRAL DIVISION

EMERY RESOURCE HOLDINGS, LLC, a Utah limited liability company, **Plaintiff,** **v.** **COASTAL PLAINS ENERGY, INC., a Texas corporation,** **Defendant.**	**MEMORANDUM DECISION AND ORDER** **Case No. 2:08-cv-907** **Magistrate Judge Paul M. Warner**

All parties in this case have consented to having United States Magistrate Judge Paul M. Warner conduct all proceedings in this matter, including entry of final judgment, with appeal to the United States Court of Appeals for the Tenth Circuit.[1] *See* 28 U.S.C. § 636(c); Fed. R. Civ. P. 73. Before the court are (1) Coastal Plains Energy, Inc.'s ("Coastal") motion for partial summary judgment;[2] (2) Emery Resource Holdings, LLC's ("Emery") motion for partial summary judgment;[3] and (3) Emery's motion to strike affidavits and exclude testimony.[4] A hearing on the motions was held on November 9, 2011. At the hearing, Coastal was represented

---

[1] *See* docket no. 12 & 33.

[2] *See* docket no. 48.

[3] *See* docket no. 57.

[4] *See* docket no. 64.

by Donald I. Schultz and Catherine L. Brabson, and Emery was represented by Christopher G. McAnany. The court has carefully reviewed the motions, memoranda, and other materials submitted by the parties. After considering the arguments of counsel and taking the motions under advisement, the court renders the following memorandum decision and order.

FACTUAL BACKGROUND[5]

Coastal is a Texas corporation which holds various oil and gas leases and operates producing natural gas wells in Emery County, Utah, on property known as the Ferron Field. Emery is a limited liability company comprised of ten individuals ("Emery's Members") who hold royalty mineral interests in the Ferron Field that are leased to Coastal for oil and gas development. Coastal and Emery's Members are not the original parties to the leases; Coastal is the successor lessee and Emery's Members are the successor lessors.

Between approximately 1952 and 1982, the original individual lessors entered into the nine[6] oil and gas leases at issue in this matter ("Subject Leases") with various oil and gas companies. Since 1957, approximately twelve natural gas wells ("Ferron Field Wells") have

---

[5] In its memorandum in opposition to Coastal's motion, Emery sets forth its "Statement of Controverted Facts." However, Emery has failed to identify any material fact in genuine dispute that would preclude summary judgment. Accordingly, the court concludes that the material background facts are undisputed.

[6] In the First Amended Complaint, Emery identified ten oil and gas leases upon which it rests its claims. Coastal contends, however, that one of the leases identified is a 1984 lease of Mack V. Bunderson that was never assigned to Coastal and that Coastal has never operated a well producing gas from the deep formations covered by that lease. Emery has not contested this assertion. As such, the court will presume that only nine leases are at issue in this case.

been installed on the property covering the Subject Leases. Only natural gas is produced and sold from the Ferron Field Wells.

In 2002, Coastal purchased the Ferron Field Wells and associated working interests in the Subject Leases from Questar Exploration and Production Company. In June of that year, Coastal assumed operation of the Ferron Field Wells. During 2002 to early 2004, Coastal did not own any interest in the Ferron Field gas gathering system; its production equipment ended at outlets of the wellhead separators. At that time, Questar Gas Management Company, a midstream gathering and processing company, owned the gas gathering equipment located between the wellhead and the inlet of the interstate pipeline, a location known as Map Point 148.

After the natural gas has been extracted from the well, it flows through a wellhead separator, which separates water from the gas stream. The gas gathering system includes the natural gas meters located near each well. The meters receive the gas downstream of Coastal's wellhead separators and connect to four-inch lateral pipelines that transport the gas from each well to a six-inch gathering trunk line. The trunk line runs about four miles to a building that contains gas-fired compressors. Compression of the gas is necessary for it to enter into and be transported on the interstate pipeline owned by Questar Pipeline Company ("Questar Pipeline") and regulated by the Federal Energy Regulatory Commission. After compression, the gas flows through a dehydrator to remove water vapor and then into a meter at an interconnection to the Questar Pipeline.

Once Coastal assumed operation of the Ferron Field Wells, it sold all of the gas it produced to Wasatch Energy, LLC ("Wasatch"). Coastal's contract with Wasatch specified that

Coastal was to deliver the gas to Wasatch at the wellhead facilities for an agreed wellhead price. From June 2002 through May 2004, Wasatch arranged with Questar Gas Management Company to provide the gas gathering services to make the gas suitable for entry into the Questar Pipeline. The contract between Coastal and Wasatch also provided that all gas delivered by Coastal must meet the quality and pressure specifications of the receiving pipeline. Wasatch paid Coastal a wellhead price calculated as an agreed mainline price, less 100% of the gathering charges Wasatch would have to pay Questar Gas Management Company and less a service fee. During that same time frame, Coastal paid the royalty owners their respective decimal interest shares of the actual proceeds that Coastal received from Wasatch under this wellhead sales agreement.

Effective with June 2004 production, Coastal began operating the Ferron Field gas gathering system that it and other working interest owners purchased from Questar Gas Management Company. Upon purchase of the gas gathering system, the owners, including Coastal as operator, invested money to design and install a more efficient replacement gas-fired compressor. Then, in 2008, Coastal purchased a replacement electric natural gas compressor. These upgrades helped to increase revenue first by reducing gas fuel use and then by eliminating gas fuel use altogether. After Coastal purchased the gas gathering system, its sales of gas to Wasatch continued, but Wasatch no longer handled or paid for gathering and compression services. As such, Wasatch paid Coastal a negotiated mainline price for the gas (less production taxes and fees), rather than a wellhead price.

Since it purchased the Ferron Field Wells, Coastal has been calculating the royalty owed to Emery's Members based on the condition and value of the gas as it flowed from the wellhead

separators. Coastal employed a "work back" method from the mainline value by deducting a gathering rate to arrive at a royalty value at the place of production. The amount of the gathering rate set by Coastal has varied over time with fluctuations in gas prices. The gathering rate as set by Coastal is also billed to the working interest owners in the leases (some own interests in the gathering system; others do not).

The royalty provisions in the Subject Leases fall into three types, although two of them are notably similar. The various royalty clauses provide as follows:

> To pay lessor one-eighth (1/8) of the proceeds received by lessee at the well for all gas (including all substances contained in such gas) produced from the leased premises and sold by lessee . . . .[7]
>
> The royalties to be paid by Lessee are . . . on gas, including casinghead gas or other gaseous substance, produced from said land and sold or used off the premises or in the manufacture of gasoline or other product therefrom, the market value at the well of one-eighth of the gas so sold or used, provided that on gas sold at the wells the royalty shall be one-eighth of the amount realized from such sale.[8]
>
> The Lessee shall pay Lessor, as royalty, one-eighth (1/8) of the proceeds from the sale of the gas, as such, for gas from wells where gas only is found . . . .[9]

Coastal and Emery filed cross-motions for partial summary judgment. Coastal seeks judgment as a matter of law on the following two issues: (1) the Subject Leases require gas

[7] Docket no. 18, Exhibits A, C, D, and E.

[8] *Id.*, Exhibits G and I.

[9] *Id.*, Exhibits F, H, and J. The royalty clause in Exhibit H is slightly different than in Exhibits F and J but the differences are not material.

royalty to be valued at the well or on the leased premises and not at a point downstream and (2) Coastal is entitled to deduct from the royalty value of gas produced from the Ferron Field Emery's Members' proportionate share of Utah ad valorem taxes, Utah conservation taxes, and Utah severance taxes. In its motion, Emery seeks judgment as a matter of law that the Subject Leases do not authorize Coastal to take deductions for Coastal's gathering and processing costs from production royalties owed to Emery's Members. Emery also moves this court for an order striking the affidavits and testimony of Coastal's experts, David E. Pierce and Jeff J. Fishman, and non-expert, Jay Neese. The court will now address the parties' respective motions.

STANDARD OF REVIEW

Summary judgment is appropriate "if the movant shows that there is no genuine dispute as to any material fact and the movant is entitled to judgment as a matter of law." Fed. R. Civ. P. 56(a). "Judgment as a matter of law is appropriate when the nonmoving party has failed to make a sufficient showing on an essential element of his or her case with respect to which he or she has the burden of proof." *Shero v. City of Grove*, 510 F.3d 1196, 1200 (10th Cir. 2007). In deciding a summary judgment motion, "'the inferences to be drawn from the underlying facts . . . must be viewed in the light most favorable to the party opposing the motion.'" *Id.* (quoting *Matsushita Elec. Indus. Co. v. Zenith Radio Corp.*, 475 U.S. 574, 587 (1986)). But "[t]he nonmoving party 'may not rest upon the mere allegations or denials of his pleadings' to avoid summary judgment." *Baccus Indus., Inc. v. Arvin Indus., Inc.*, 939 F.2d 887, 891 (10th Cir. 1991) (quoting *Anderson v. Liberty Lobby, Inc.*, 477 U.S. 242, 249 (1986)). Furthermore, the mere fact that the parties have filed cross-motions for partial summary judgment does not

necessarily indicate that summary judgment is proper for either party. *See Atlantic Richfield Co. v. Farm Credit Bank of Wichita*, 226 F.3d 1138, 1148 (10th Cir. 2000); *see also Buell Cabinet Co., Inc. v. Sudduth*, 608 F.2d 431, 433 (10th Cir. 1979) ("Cross-motions for summary judgment are to be treated separately; the denial of one does not require the grant of another.").

In addition, Emery's claim is premised on a novel theory of Utah oil and gas law on which the Utah Supreme Court has not previously ruled. "[W]hen presented with a novel issue of state law, a federal court must predict how the state's highest court would decide the issue. . . . In doing this, a federal court may examine all resources, including considered dicta, treatises, law reviews and well-reasoned authority from other jurisdictions." *Schoepe v. Zions First Nat. Bank*, 750 F. Supp. 1084, 1087-88 (D. Utah 1990), *aff'd sub nom*, *Lion Hill Mines Through Schoepe v. Zions First Nat. Bank*, 952 F.2d 1401 (10th Cir. 1992).

DISCUSSION

A. Cross-Motions for Partial Summary Judgment

The parties agree that in this diversity case, the substantive law of Utah governs the Subject Leases. *See Haberman v. Hartford Ins. Group*, 443 F.3d 1257, 1264 (10th Cir. 2006). Under Utah law, "[t]he general principles governing the interpretation of contracts apply to documents conveying mineral interests." *Heiner v. S.J. Groves & Sons Co.*, 790 P.2d 107, 110 (Utah Ct. App. 1990). To determine the meaning and original parties' intent under the Subject Leases, the court must first examine the language of the contracts. *See Café Rio, Inc. v. Larkin-Gifford-Overton, LLC*, 207 P.3d 1235, 1240 (Utah 2009). In contract interpretation, courts should "consider each contract provision . . . in relation to all of the others, with a view toward

giving effect to all and ignoring none." *Id.* (quotations and citation omitted). "If the language within the four corners of the contract is unambiguous, the parties' intentions are determined from the plain meaning of the contractual language, and the contract may be interpreted as a matter of law." *Green River Canal Co. v. Thayn*, 84 P.2d 1134, 1141 (Utah 2003).

Extrinsic evidence of the parties' intent is considered in contract interpretation only when the language of the contract is ambiguous. *See Café Rio, Inc.*, 207 P.3d at 1240. An ambiguous contract term or provision "is capable of more than one reasonable interpretation because of uncertain meanings of terms, missing terms, or other facial deficiencies." *Id.* (quotations and citation omitted). In addition, "[u]nder the well-established rule of construction *ejusdem generis*, [courts shall] determine the meaning of a general contractual term based on the specific enumerations that surround that term." *Id.* (quotations and citation omitted).

The Utah Supreme Court has held that "contractual ambiguity can occur in two different contexts: (1) facial ambiguity with regard to the language of the contract and (2) ambiguity with regard to the intent of the contracting parties." *Daines v. Vincent*, 190 P.3d 1269, 1275-76 (Utah 2008). Facial ambiguity is a question of law to be determined by the court. *See id.* at 1276. If the court makes the initial determination that a contract is facially ambiguous, only then will parol evidence of the parties' intentions be admitted. *See id.* at 1276.

To determine whether a contract or provision is facially ambiguous, Utah courts employ a two part test. *See id.* First, "[w]hen determining whether a contract is ambiguous, any relevant evidence must be considered. Otherwise, the determination of ambiguity is inherently one-sided, namely, it is based solely on the extrinsic evidence of the judge's own linguistic education and

experience." *Id.* (quotations and citations omitted). Second, after the court considers relevant evidence of the parties' respective interpretations, it must make certain that the proffered interpretations are reasonable in light of the contractual language. *See id.*

In *Ward*, the Utah Supreme Court sought to establish a rational framework for determining whether a contract is facially ambiguous that would permit a court to "consider the writing in the light of the surrounding circumstances." *Ward*, 907 P.2d at 268. At the same time, a court may not "allow surrounding circumstances to create ambiguity where the language of a contract would not otherwise permit." *Id.* Therefore, "a finding of ambiguity after a review of relevant, extrinsic evidence is appropriate only when 'reasonably supported by the language of the contract.'" *Id.* (quoting *Ward*, 907 P.2d at 268). With the foregoing in mind, the court now turns to the royalty provisions in the Subject Leases to determine whether they are ambiguous.

Four of the Subject Leases state that the lessee is

> [t]o pay lessor one-eighth (1/8) of the proceeds received by lessee *at the well* for all gas (including all substances contained in such gas) produced from the leased premises and sold by lessee . . . .[10]

The court concludes that the "proceeds received by lessee *at the well*"[11] language is clear and unambiguous. The parties intended for the royalty value to be determined based on the gas as it is produced from the wells and not at some point downstream. The next sentence provides further support that the parties intended for the gas to be valued at the wellhead:

[10] Docket no. 18, Exhibits A, C, D, and E (emphasis added).

[11] *Id.* (emphasis added).

> if such gas is used by lessee off the leased premises or used by lessee for the manufacture of casinghead gasoline or other products, to pay to lessor one-eighth (1/8) of the prevailing market price *at the well* for the gas so used.[12]

This sentence demonstrates that the intention of the original parties was for the lessors to be paid on the production value at the current market price of the gas at the well and not at a downstream location. The plain meaning of this language shows that the parties intended and bargained for a royalty value based on the lower wellhead value or proceeds to be obtained for gas as it was produced, and not a royalty to be based on a higher downstream value obtained by investments in transportation, compression, dehydration, or processing at the sole expense of the lessee.

Two of the Subject Leases also set forth unambiguous language regarding the royalty valuation:

> The royalties to be paid by Lessee are . . . on gas, including casinghead gas or other gaseous substance, produced from said land and sold or used off the premises or in the manufacture of gasoline or other product therefrom, the market value at the well of one-eighth of the gas so sold or used, provided that on gas sold at the wells the royalty shall be one-eighth of the amount realized from such sale.[13]

The language of this provision again provides that the royalty to be paid is the "market value at the well" for "gas sold at the wells."[14] On its face, this language demonstrates that there is only

---

[12] *Id.* (emphasis added).

[13] *Id.*, Exhibits G and I.

[14] *Id.*

one reasonable interpretation: the parties intended the royalty value to be based on the wellhead value or proceeds on the gas as produced from the well.

In three of the Subject Leases, the royalty provision provides:

> The Lessee shall pay Lessor, as royalty, one-eighth (1/8) of the proceeds from the sale of the gas, as such, for gas from wells where gas only is found . . . .[15]

While this lease language is not as clear as the royalty language contained in the first two leases, the qualifying phrase "as such, for gas from wells where gas only is found" can be reasonably and fairly construed to mean the sale of the gas "as such" or, in other words, in the condition in which the gas is found when produced "from" the wells.[16] However, because courts must "attempt to harmonize all of the contract's provisions and all of its terms when determining whether the plain language of the contract is ambiguous," the court will examine the paragraphs surrounding this royalty language. *Gillmor v. Macey*, 121 P.3d 57, 65 (Utah Ct. App. 2005) (quotations and citations omitted).

The immediately preceding paragraph provides the lessee with two options for valuing oil production. Specifically,

> [t]he lessee shall deliver to the credit of the lessor as royalty, free of cost, in the pipe line to which lessee may connect its wells, the equal one-eighth (1/8) part of all oil produced and saved from the leased premises, or at the lessee's option, may pay to the lessor for such one-eighth (1/8) royalty the market price for oil of like grade

---

[15] Docket no. 18, Exhibits F, H, and J. The royalty clause in Exhibit H is slightly different than in Exhibits F and J but the differences are not material.

[16] *Id.*, Exhibits F, H, and J.

> and gravity prevailing in the field where produced on the day such oil is run in the pipe line, or into storage tanks.[17]

In the first option, the parties agree that the lessee may deliver as royalty one-eighth of the oil produced in the pipeline free of cost, meaning that the lessor would be responsible for his or her share of any costs to transport, refine, or otherwise handle the one-eighth share of oil after extraction from well for entry into the pipeline. The lessor could, of course, sell the share for a lower wellhead price to a buyer willing to pay those post-production costs. The lessee's alternative option would allow a royalty payment to be made on one-eighth of "the market price for oil of like grade and gravity prevailing in the field where produced on the day such oil is run into the pipeline, or into storage tanks."[18] Thus, the parties intended that a dollar amount royalty valuation would be based on the prevailing market rate of like-quality oil in the same field and produced the same day, not based on the market value of the oil in an improved condition at some downstream point.

The sentence following the gas royalty provision provides that the lessee must "pay lessor for gas produced from any oil well and used off the premises or in the manufacturing of gasoline or any other product a royalty of one-eighth (1/8) of the market value, at the mouth of the well, payable monthly at the prevailing market price."[19] Again, the plain language of this

---

[17] *Id.*, Exhibits F, H, and J.

[18] *Id.*

[19] *Id.*, Exhibits F and J. The sentence following the gas royalty provision in Exhibit H is somewhat different than in Exhibits F and J. It provides that when gas is not sold, the lessee must pay an annual amount of $50.00 dollars for each well on the leased premises. It also provides that the lessor may use the gas from the wells on the premises free of charge at the sole

provision demonstrates that the parties contemplated that the royalty for the sale of gas produced from an oil well should be determined by the market value at the mouth of the well, not after the gas has been refined for gasoline or other similar product downstream.

Reading the paragraphs together, the court concludes that the parties intended all products produced from the wells to be valued at the prevailing market rate at the wellhead. In light of the surrounding paragraphs, the court cannot conclude that the parties intended the royalty valuation point to be at some location downstream and away from the leased premises. The language of the Subject Leases, considered as a whole, does not support that interpretation.

Emery frames the issue in a different manner. Emery first notes that a royalty interest in an oil and gas lease is a "share of production free of the costs of production." Eugene O. Kuntz, *A Treatise on the Law of Oil and Gas* § 40.1 (1989); *see also Flying Diamond Oil Corp. v. Newton Sheep Co.*, 776 P.2d 618, 629 (Utah 1989) (stating that "[a] royalty interest is a share of production, if, as and when there is production, free of the expenses of production." (quotations can citations omitted)). Emery contends that Coastal is improperly deducting from royalties amounts for gathering, dehydration, compression, and acquisition of the gathering system and that those activities are, in fact, production costs attributable solely to Coastal. To determine whether the Subject Leases allow for these deductions from royalties, Emery urges this court to

---

risk of lessor. The last sentence of that paragraph states that "[t]he lessee shall pay to lessor for gas produced from any oil well and used by the lessee for the manufacture of gasoline, or any other product, as royalty, one-eighth of the market value of such gas." By using the phrases "gas produced" and "such gas," the court concludes that the parties intended the valuation point to be at the production of the gas from the well, not after the gas has been refined for gasoline or another similar product.

examine to the language of the Subject Leases and decide whether they address the allocation of costs. Emery correctly states that the Subject Leases are silent with respect to cost allocation. Because the Subject Leases are silent with respect to deductions, Emery contends that the court must recognize the implied covenant to market that exists in oil and gas leases. The implied covenant to market provides the lessor assurance that the lessee will diligently market the gas for a reasonable price without sitting speculatively on the lease. *See, e.g.*, *Rogers v. Westerman Farm Co.*, 29 P.3d 887, 903 (Colo. 2001).

Emery argues that this court should predict that the Utah Supreme Court would likely adopt the "first marketable product doctrine" as set forth by the Colorado Supreme Court and adopted by courts in Kansas, Oklahoma, and West Virginia. *Id.* at 904-06. This doctrine provides that lessees should calculate royalty payments on the basis of the value or price of the gas production at the location where the lessee first obtains a marketable product, which may be a location that is far downstream of the wellhead. *See* Brian C. Keeling & Karolyn King Gillespie, *The First Marketable Product Doctrine: Just What is the "Product"?*, 37 St. Mary's L.J. 1, 4 (2005). The doctrine "requires the lessee to pay any costs incurred in turning the unmarketable gas into a marketable product" and provides that "[o]nce the gas is marketable, additional costs incurred to enhance the products['] marketability are shared between the lessee and the lessor." *Bice v. Petro-Hunt, L.L.C.*, 768 N.W.2d 496, 501 (N.D. 2009). While a minority of states have adopted the first marketable product doctrine, those states adopting the doctrine have failed to articulate a clear standard for determining when a marketable product has been created. *See* Keeling & Gillespie, *The First Marketable Product Doctrine: Just What is the*

"Product"?, 37 St. Mary's L.J. at 79 (providing an in depth analysis of the first marketable product doctrine and concluding that the doctrine "has thrown oil and gas royalty law into chaos" as "[f]our different states have emerged with four different versions" of the doctrine). While Emery urges this court to examine the specific language of the Subject Leases to determine the original parties' intent, it also asks this court to ignore the parties' express "at the well" language and impose obligations on Coastal not contemplated by the original parties to the Subject Leases. The court is unwilling to do so.

The majority of courts to consider the topic have found "at the well" royalty clauses to mean that natural gas is valued for royalty purposes at its wellhead location and condition. *See Heritage Res., Inc. v. Nationsbank*, 939 S.W.2d 118, 122 (Tex. 1996) ("Although it is not subject to the costs of production, royalty is usually subject to post-production costs, including taxes, treatment costs to render it marketable, and transportation costs." (quotations and citations omitted)); *see also Elliott Indus. Ltd. P'ship v. BP America Prod. Co.*, 407 F.3d 1091, 1109-10 (10th Cir. 2005) (noting that "'at the well' royalty obligations do require royalty payments based on the unprocessed gas as it emerges at the wellhead"); *Piney Woods Country Life Sch. v. Shell Oil Co.*, 726 F.2d 225, 230-31 (5th Cir. 1984) (interpreting Mississippi law and stating that "[t]he royalty compensates the lessor for the value of the gas at the well: that is, the value of the gas after the lessee fulfills its obligation under the lease to produce the gas at the surface, but before the lessee adds to the value of the gas by processing or transporting it"); *Atlantic Richfield Co. v. State*, 262 Cal. Rptr. 683, 688 (Cal. Ct. App. 1989) ("When the term 'at the well' is used in connection with 'market price' . . . the lessor, such as [the] State, bears its proportionate share

of processing costs incurred downstream of the well."); *Babin v. First Energy Corp.*, 693 So.2d 813, 815 (La. Ct. App. 1997) (holding that the costs of severance taxes, transportation, processing, and treatment are considered to be post-production costs and are, therefore, borne proportionately by the lessee and the royalty owner); *Schroeder v. Terra Energy, Ltd.*, 565 N.W.2d 887, 894 (Mich. Ct. App. 1997) (adopting the "at the well" rule because it "better conforms with the parties' intent"); *Montana Power Co. v. Kravik*, 586 P.2d 298, 303 (Mont. 1978) (holding that the market price is understood to mean the current market price being paid for gas at the well where it is produced). As noted by the North Dakota Supreme Court, the "at the well" rule provides that "any costs incurred by the lessee after the [gas] reaches the wellhead, whether to improve the quality of the [gas] or to transport it to a market where it may be sold may be deducted before the royalty is calculated." *Bice*, 768 N.W.2d at 501 (quotations and citation omitted).

States that follow the majority "at the well" rule allow a lessee to utilize one of the following two methods to calculate the market value at the wellhead: (1) the comparable sales method or (2) the work-back method. *See id.* In the comparable sales method, the lessee averages the comparable sales "at the same time and in the same field, for oil or gas of comparable quality, quantity, and availability." *Id.* (quotations and citation omitted). In the work-back method, the lessee calculates the market value at the well by deducting post-production costs that it incurred after the gas was extracted from the well. *See id.*

While the Utah Supreme Court has not ruled directly on this issue, its limited case law provides helpful instruction. In *Rimledge Uranium and Mining Corp. v. Federal Resources*

Corp., 374 P.2d 20 (Utah 1962), the court interpreted a royalty reserved in a deed of uranium mining claims. The deed set forth "a royalty of fifteen percent (15%) of all gross proceeds from the sale of ore." *Id.* at 20. For a few years, the mining company sold the uranium ore in raw or unconcentrated form as produced from the mine to the Atomic Energy Commission ("AEC"). *See id.* at 21. At that time, the AEC or its agents were the only entities authorized by federal law to buy uranium. *See id.* A few years later, the AEC granted a license to a third-party operator to run a uranium mill, and in 1958 the mining company stopped selling raw ore, entered into a processing contract with the third-party, and began selling only concentrated ore produced at the uranium mill. *See id.* The company deducted the costs of third-party processing when it paid royalties under the deed. *See id.* The royalty owner sued for royalties based on the downstream value of concentrated ore after processing in the mill. *See id.* at 21-22. The Utah Supreme Court analyzed the contract language and found the parties' intent as follows:

> Plaintiffs place great stress upon the dictionary definitions of the words, 'gross,' 'proceeds,' 'sale,' and 'ore.' We do not quarrel with these definitions in the abstract. However, the term 'gross proceeds,' regardless of any abstract definition must be defined and construed in terms of the concrete context in which it was used in the various assignments. Specifically, at what stage of the whole commercial process did the parties intend 'gross proceeds' to apply?
>
> It is our opinion, considering all the factors involved and the case authority (none of which is very close in point), that the parties intended the base for royalty payments to be the proceeds realized from the sale of raw ore, or, if there is no sale of raw ore, then the fair market value of raw ore in the vicinity of the mining activities.

Id. at 22; *see also Richardson v. Homestake Mining Co.*, 322 F.2d 329, 331-32 (10th Cir. 1963) (applying *Rimledge* in a nearly identical case). Likewise, this court also concludes that the original parties to the Subject Leases intended to for the valuation point to be at the wellhead before the raw gas is gathered, dehydrated, and compressed.

The *Rimledge* court further noted that the plaintiffs' interpretation would entitle them "to the gross proceeds of the sale of ore, as long as it remained ore, no matter how much value had been added by the defendants, and the plaintiffs would reap the advantage of this added value created by the defendants at the latter's expense." *Rimledge*, 374 P.2d at 23. Similarly, if this court adopted Emery's proposed interpretation, Emery's Members would unjustly profit from the effort put forth by Coastal to get the gas to the Questar Pipeline. Like the court in *Rimledge*, this court concludes that it does not make sense to have a lessor and lessee agree that the royalty valuation point is at the mine or the wells (as the case may be) when sales actually occur there, only to have that point change to some other undefined downstream location if the market were to change. *See id.* at 22 ("To argue that the parties intended that 'gross proceeds' implies a different basis at different times is quite unrealistic.").

Like the majority of states to adopt the "at the well" rule, this court concludes that if the royalty is not valued "at the wells" when gas is sold downstream, then the Subject Leases are left without a defined royalty valuation point or with a royalty valuation point that can change over time. That is a result the parties to the lease could not have reasonably intended. Accordingly, this court concludes that the gas royalty under the Subject Leases must be valued at the wells in

the condition at which the gas flows from the wellhead separators and enters the Ferron Field gas gathering system.

Coastal also requests a ruling that, as a matter of law, it is entitled to deduct the proportionate share of Utah taxes from the royalty value of gas produced from the Ferron Field. The Utah statutes that impose each of the three types of production tax specify: (1) the tax obligation or liability rests with the royalty interest owner as to his or her proportionate share of production; (2) the operator or producer must remit or pay the tax on behalf of the royalty interest

owners; and (3) the operator or producer is to collect or deduct the amounts so paid from the royalty owners' payments. *See* Utah Code Ann. §§ 40-6-14, 59-5-102, and 59-2-210. Emery does not specifically address Coastal's argument regarding these deductions. Accordingly, and for good cause appearing, the court concludes that Coastal may deduct the proportionate share of the applicable Utah taxes from the royalty amount.

In summary, the court concludes that the royalty language of the Subject Leases is unambiguous and that the parties intended for the natural gas produced from the Ferron Field Wells to be valued at the prevailing market rate at the wellhead. Thus, Coastal may deduct the applicable taxes and post-production costs incurred from the wellhead separators to the Questar Pipeline to determine the market value at the well prior to calculating the royalty amount.

B. Emery's Motion to Strike

Emery seeks an order striking the affidavits and testimony of Coastal's experts, David E. Pierce and Jeff J. Fishman. Emery argues that the proffered testimony should be stricken

because (a) it contains improper legal opinions invading the province of the court to instruct the jury, (b) it improperly attempts to testify as to industry custom, and (c) it includes irrelevant parol evidence concerning the natural gas regulatory environment for periods predating the conduct in

question in this case. Emery also seeks to strike the affidavit of Coastal's non-expert, Jay Neese, on the grounds that it includes irrelevant parol evidence pertaining to the period before the deregulation of natural gas markets.

The court did not rely upon the testimony or affidavits provided by Coastal in ruling on the parties' cross-motions for summary judgment. Accordingly, the court concludes that Emery's motion to strike is moot.

CONCLUSION

Based on the foregoing, Coastal's motion for partial summary judgment[20] is **GRANTED**, Emery's motion for partial summary judgment[21] is **DENIED**, and Emery's motion to strike[22] has been rendered **MOOT**.

IT IS SO ORDERED.

DATED this 30th day of March, 2012.

BY THE COURT:

PAUL M. WARNER
United States Magistrate Judge

---

[20] *See* docket no. 48.

[21] *See* docket no. 57.

[22] *See* docket no. 64.